



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION VIII

999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

DEC 19 1997

Ref: 8P2-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Kathy Turner
Petroleum Engineering Technician
Petroglyph Operating Company, Inc.
6209 North Highway 61
Hutchinson, Kansas 67502

RE: UIC MINOR PERMIT MODIFICATION
Conversion of Additional Well to
Antelope Creek Waterflood
EPA Area Permit UT2736-00000
Duchesne County, Utah

Dear Ms. Turner:

Your letter of December 4, 1997, requesting that the following production well be converted and reinstated as a Class II enhanced oil recovery well and added to the Antelope Creek Waterflood, as authorized under EPA Area Permit #UT2736-00000, is hereby granted.

<u>NAME</u>	<u>LOCATION</u>	<u>EPA WELL PERMIT NO.</u>
Ute Tribal #21-03	NE/NW Section 21 T 5 S - R 3 W Duchesne County, UT	#UT2736-04363

This additional well is within the boundary of the existing area permit for the Antelope Creek Waterflood (UT2736-00000), and this addition is made by minor permit modification according to the terms and conditions of that permit. Unless specifically mentioned in this Minor Permit Modification, all terms and conditions of the original permit will apply to the construction, operation, monitoring, and plugging and abandonment of this additional injection well. The proposed well location, well schematic, conversion procedures, plugging and abandonment plan and schematic, submitted by your office, have been reviewed and approved as follows:

- (1) The conversion of this production well has been reviewed, and found satisfactory, therefore, no corrective action is required.



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RE: UIC MIN
Conversion
Antelope
EPA Area
Duchesne

*Scan under
66
UT 20736 - 00000
Modification - Minor
Mod Approved 12/19/97
Will also be linked
to the individual UIC
Well permit UT 20736 -
04363 under 81 Add
Well to Area Permit.*

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- (2) **Maximum injection pressure (Pmax)** - the permittee submitted a list of five (5) individual zones, within the Ute Tribal #21-03, which were individually fraced and established an average fracture gradient (Fg) of 0.95 psi/ft. which was derived from instantaneous shut-in pressures (ISIP) from each zone. This Fg is acceptable to the Environmental Protection Agency (EPA), and a theoretical maximum allowable surface injection pressure (Pmax), for this well, may be calculated as shown below:

$$P_{max} = [Fg - 0.433 (Sg)] d$$

Where: P_{max} = Maximum surface injection pressure at wellhead

d = 4714' shallowest perforations

Sg = Specific gravity of injected water

$$P_{max} = [0.95 - .433 (1.00)] 4714$$

$$P_{max} = 2451 \text{ psig}$$

Until such time as the permittee demonstrates that a fracture gradient other than 0.95 psi/ft applies to the disposal zones of this newly converted well, the maximum allowable wellhead injection pressure (P_{max}) for this well will be 2451 psig.

- (3) The plugging and abandonment plan and schematic, submitted by your office, has been reviewed, and approved.

Prior to commencing injection into this well, permittee must fulfill permit condition Part II, C. 2. and have received **separate written authorization to inject by the Environmental Protection Agency**. In summary, these requirements for your newly permitted injection well are:

- (1) All conversion is complete and the permittee has submitted a completed **Well Rework Record (EPA Form 7520-12)**.
- (2) The pore pressure has been determined.
- (3) The well has successfully completed and passed a **mechanical integrity test (MIT)**; MIT guidance and EPA form enclosed.

All other provisions and conditions of the permit remain as originally issued.

If you have any questions, please contact Mr. Chuck Williams at (303) 312-6625.

Also, please direct the above requirements to Mr. Williams at the above letterhead address, citing MAIL CODE 8P2-W-GW. Thank you for your continued cooperation.

Sincerely,



Kerrigan G. Clough
Assistant Regional Administrator
Office of Pollution Prevention,
State and Tribal Assistance

Enclosure: MIT Guidance and EPA Form

cc: Mr. Ronald Wopsock, Chairman
Uintah & Ouray Business Committee

Ms. Elaine Willie, Environmental Director
Ute Indian Tribe

Norman Cambridge
BIA - Uintah & Ouray Agency

Mr. Jerry Kenczka
BLM - Vernal District Office

Mr. Gilbert Hunt
State of Utah Natural Resources
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CEW
 P2-W-GW
 12/9/97

12/11/97
 P2-W-GW

8P2-TA
 Lewis
 12/15/97

12/17/97
 8P2-W-GW
 12-17

12/12/97 LQ
 mailed 12/31/97 LQ

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Original signed
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Assistant Regional Administrator
Office of Pollution Prevention,
State and Tribal Assistance
Kerrigan G. Clough
Assistant Regional Administrator
Office of Pollution Prevention,
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Mr. Gilbert Hunt
State of Utah Natural Resources
Division of Oil, Gas & Mining

FCD: December 9, 1997, Chuck W., F:\DATA\WP\PETROGLF\MNRMD-21.03A



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999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

JUL - 6 1995

Ref: 8WM-DW

MEMORANDUM

SUBJECT: Final Guidance for Conducting a Pressure Test to Determine if a Well Has Leaks in the Tubing, Casing or Packer

FROM: Tom Pike, Chief UIC Direct Implementation *[Signature]*

TO: UIC Direct Implementation Permit Writers

Introduction

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

- (1) There is no significant leak in the tubing, casing or packer; and
- (2) There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore.

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the downhole components of an injection well, usually tubing, casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equivalent form containing the necessary information. A pressure recording chart documentating the actual annulus test pressures must be attached to the form.

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or



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packer). The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all class I and II wells. Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

Pressure Test Description

Test Frequency

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required at least every five (5) years. If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. The Regional UIC program must be notified of the workover and the proposed date of the pressure test. The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate. Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

1. Class I hazardous waste injection wells; initially [40 CFR 146.68(d)(1)] and annually thereafter;
2. Class I non-hazardous waste injection wells; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);
3. Class II wells with tubing, casing and packer; initially and at least every five (5) years thereafter;

4. Class II wells with tubing cemented in the hole; initially and every one (1) or two (2) years thereafter depending on well specific conditions (See Region VIII UTC Section Guidance #36);
5. Class II wells which have been temporarily abandoned (TAd) must be pressure tested after being shut-in for two years; and
6. Class III uranium extraction wells; initially.

Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.

Test Criteria

1. The duration of the pressure test is 30 minutes.
2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.
3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.
4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equivalent form. A pressure recording chart documenting the actual annulus test pressures must be attached to the submittal. The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.
2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.
3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.
4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.
5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to

the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:

6. Read tubing pressure and record on the form. If the well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.
7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.
8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.
9. Hook-up well to pressure source and apply pressure until test value is reached.
10. Immediately disconnect pressure source and start test time. (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted.) The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.
11. Record tubing and annulus pressure values every five (5) minutes.
12. At the end of the test, record the final tubing pressure.
13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.
14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up

letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.

15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.
16. Return to office and prepare follow-up.

Attachment

Mechanical Integrity Test

Casing or Annulus Pressure Test for Well UT2736-04363

U.S. Environmental Protection Agency
Underground Injection Control Program, UIC Implementation Section, 8WM-DW
999 18th Street, Suite 500, Denver, CO 80202-2466
This form was printed on 04/15/1997.

EPA Witness: _____ Date / /

Test conducted by: _____

Others present: _____

UTE TRIBAL #21-03 ANTELOPE CREEK Petroglyph Operating Company, Inc., Last MIT: No record / / Max Allowed Press psig 199	2R UC as of / / NENW 21 05S 03W Hutchinson, KS Op ID PTG01 Max Reported Press psig
---	---

Is this a regularly scheduled test? ☐ Yes ☐ No
 Initial test for permit? ☐ Yes ☐ No
 Test after well rework? ☐ Yes ☐ No

Well injecting during test? ☐ NO ☐ YES _____ BPD

Initial casing/tubing annulus pressure _____ psig
 Does the annulus pressure build back up? ☐ Yes ☐ No

TUBING PRESSURE					
Initial	psig	psig	psig		
End of Test	psig	psig	psig		
CASING/TUBING ANNULUS PRESSURE					
Time	Test #1	Test #2	Test #3		
0 min	psig	psig	psig		
5					
10					
15 min					
20					
25					
30 min					
Result (circle)	Pass Fail	Pass Fail	Pass Fail		

12/31/87 CW 3185C

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

DEC 31 1997

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Ms. Kathy Turner
Geology/Petroleum Engineering
Technician
Petroglyph Operating Company, Inc.
P.O. Box 1839
Hutchinson, KS 67504-1839

4a. Article Number

P 164 014 412

4b. Service Type

- | | |
|---|---|
| <input type="checkbox"/> Registered | <input checked="" type="checkbox"/> Certified |
| <input type="checkbox"/> Express Mail | <input type="checkbox"/> Insured |
| <input type="checkbox"/> Return Receipt for Merchandise | <input type="checkbox"/> COD |

7. Date of Delivery

JAN - 5 1998

5. Received By: (Print Name)

Kristine L. Brown

6. Signature: (Addressee or Agent)

X Kristine L. Brown

8. Addressee's Address (Only if requested and fee is paid)

JAN 8 1998

PS Form 3811, December 1994

Domestic Return Receipt

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

12/31/97 CW 3185C

P 164 014 412

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail (See reverse)

Sent to	
Ms. Kathy Turner	
Street & Number	
Geology/Petroleum Engineering	
Technician	
Post Office, State, & ZIP Code	
Petroglyph Operating Company,	
P.O. Box 1839 Inc.	
Hutchinson, KS 67504-1839	
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	\$
Postmark or Date	

PS Form 3800, April 1995